CONTANGO OIL & GAS CO
Form 10-Q
August 08, 2018
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2018

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number 001-16317

CONTANGO OIL & GAS COMPANY

(Exact name of registrant as specified in its charter)

DELAWARE	95-4079863
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
717 TEXAS AVENUE, SUITE 2900	77002

HOUSTON, TEXAS
(Address of principal executive offices) (Zip Code)

(713) 236-7400

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	Accelerated filer
Non-accelerated filer	Smaller reporting company
Emerging growth company	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

The total number of shares of common stock, par value $0.04 per share, outstanding as of August 6, 2018 was 25,723,135.

Table of Contents

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

QUARTERLY REPORT ON FORM 10-Q

FOR THE SIX MONTHS ENDED JUNE 30, 2018

TABLE OF CONTENTS

All references in this Quarterly Report on Form 10-Q to the “Company”, “Contango”, “we”, “us” or “our” are to Contango Oil Gas Company and its subsidiaries.

Table of Contents

Item 1. Consolidated Financial Statements

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except shares)

	June 30, 2018 (unaudited)	December 31, 2017
CURRENT ASSETS:		
Cash and cash equivalents	$ —	$ —
Accounts receivable, net	10,927	13,059
Prepaid expenses	1,540	1,892
Current derivative asset	161	822
Total current assets	12,628	15,773
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	1,194,753	1,239,662
Unproved properties	27,249	35,243
Other property and equipment	1,272	1,272
Accumulated depreciation, depletion and amortization	(883,321)	(930,220)
Total property, plant and equipment, net	339,953	345,957
OTHER NON-CURRENT ASSETS:		
Investments in affiliates	18,696	18,464
Long-term derivative asset	152	—
Deferred tax asset	424	424
Other	595	835
Total other non-current assets	19,867	19,723
TOTAL ASSETS	$ 372,448	$ 381,453
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 42,111	$ 46,755
Current derivative liability	2,951	1,765
Current asset retirement obligations	1,209	2,017
Total current liabilities	46,271	50,537
NON-CURRENT LIABILITIES:		
Long-term debt	80,827	85,380
Long-term derivative liability	915	300
Asset retirement obligations	19,722	20,388
Other long term liabilities	3,541	248
Total non-current liabilities	105,005	106,316
Total liabilities	151,276	156,853
COMMITMENTS AND CONTINGENCIES (NOTE 11)		

SHAREHOLDERS' EQUITY:		
Common stock, $0.04 par value, 50 million shares authorized, 31,156,772 shares issued and 25,739,282 shares outstanding at June 30, 2018, 30,873,470 shares issued and 25,505,715 shares outstanding at December 31, 2017	1,235	1,223
Additional paid-in capital	305,523	302,527
Treasury shares at cost (5,417,490 shares at June 30, 2018 and 5,367,755 shares at December 31, 2017)	(128,778)	(128,583)
Retained earnings	43,192	49,433
Total shareholders' equity	221,172	224,600
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 372,448	$ 381,453

The accompanying notes are an integral part of these consolidated financial statements

Table of Contents

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(unaudited)		(unaudited)	
REVENUES:				
Oil and condensate sales	$ 9,607	$ 6,483	$ 18,418	$ 12,025
Natural gas sales	5,848	11,135	14,457	22,275
Natural gas liquids sales	2,993	2,658	6,010	5,400
Total revenues	18,448	20,276	38,885	39,700
EXPENSES:				
Operating expenses	6,478	6,329	13,405	13,162
Exploration expenses	394	284	863	375
Depreciation, depletion and amortization	9,498	12,714	19,983	24,485
Impairment and abandonment of oil and gas properties	777	1,401	4,104	1,431
General and administrative expenses	5,354	5,833	12,080	12,429
Total expenses	22,501	26,561	50,435	51,882
OTHER INCOME (EXPENSE):				
Gain (loss) from investment in affiliates, net of income taxes	(475)	166	232	1,950
Gain (loss) from sale of assets	1,370	(420)	10,817	2,520
Interest expense	(1,262)	(925)	(2,671)	(1,684)
Gain (loss) on derivatives, net	(2,610)	1,487	(3,642)	4,583
Other income (expense)	3	61	882	(27)
Total other income (expense)	(2,974)	369	5,618	7,342
NET LOSS BEFORE INCOME TAXES	(7,027)	(5,916)	(5,932)	(4,840)
Income tax provision	(151)	(118)	(309)	(309)
NET LOSS	$ (7,178)	$ (6,034)	$ (6,241)	$ (5,149)
NET LOSS PER SHARE:				
Basic	$ (0.29)	$ (0.24)	$ (0.25)	$ (0.21)
Diluted	$ (0.29)	$ (0.24)	$ (0.25)	$ (0.21)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic	24,933	24,671	24,863	24,639
Diluted	24,933	24,671	24,863	24,639

The accompanying notes are an integral part of these consolidated financial statements

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Six Months Ended June 30,	
	2018	2017
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (6,241)	$ (5,149)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	19,983	24,485
Impairment of natural gas and oil properties	3,890	1,400
Exploration recovery	—	(232)
Gain on sale of assets	(10,817)	(2,520)
Gain from investment in affiliates	(232)	(1,950)
Stock-based compensation	3,008	3,078
Unrealized loss (gain) on derivative instruments	2,311	(4,327)
Changes in operating assets and liabilities:		
Decrease in accounts receivable & other receivables	2,132	5,044
Decrease (increase) in prepaids	352	(402)
Decrease in inventory	—	123
Decrease in accounts payable & advances from joint owners	(2,027)	(41)
Decrease in other accrued liabilities	(2,618)	(1,260)
Increase (decrease) in income taxes payable, net	229	(201)
Other	3,293	61
Net cash provided by operating activities	$ 13,263	$ 18,109
CASH FLOWS FROM INVESTING ACTIVITIES:		
Natural gas and oil exploration and development expenditures	$ (30,077)	$ (35,553)
Additions to furniture & equipment	—	(39)
Sale of furniture & equipment	—	12
Sale of oil & gas properties	21,562	670
Net cash used in investing activities	$ (8,515)	$ (34,910)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	$ 130,677	$ 113,506
Repayments under credit facility	(135,230)	(96,544)
Purchase of treasury stock	(195)	(161)
Net cash provided by (used in) financing activities	$ (4,748)	$ 16,801
NET CHANGE IN CASH AND CASH EQUIVALENTS	$ —	$ —
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	—	—
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ —	$ —

The accompanying notes are an integral part of these consolidated financial statements

Table of Contents

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

(in thousands, except number of shares)

	Common Stock Shares (unaudited)	Amount	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Shareholders' Equity
Balance at December 31, 2017	25,505,715	$ 1,223	$ 302,527	$ (128,583)	$ 49,433	$ 224,600
Treasury shares at cost	(49,735)	—	—	(195)	—	(195)
Restricted shares activity	283,302	12	(12)	—	—	—
Stock-based compensation	—	—	3,008	—	—	3,008
Net loss	—	—	—	—	(6,241)	(6,241)
Balance at June 30, 2018	25,739,282	$ 1,235	$ 305,523	$ (128,778)	$ 43,192	$ 221,172

The accompanying notes are an integral part of these consolidated financial statements

Table of Contents

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Organization and Business

Contango Oil & Gas Company (collectively with its subsidiaries, “Contango” or the “Company”) is a Houston, Texas based, independent oil and natural gas company. The Company’s business is to maximize production and cash flow from its offshore properties in the shallow waters of the Gulf of Mexico (“GOM”) and onshore properties in Texas and Wyoming and to use that cash flow to explore, develop, exploit, increase production from and acquire crude oil and natural gas properties in West Texas, the onshore Texas Gulf Coast and the Rocky Mountain regions of the United States.

The following table lists the Company’s primary producing areas as of June 30, 2018:

Location	Formation
Gulf of Mexico	Offshore Louisiana - water depths less than 300 feet
Madison and Grimes counties, Texas	Woodbine (Upper Lewisville)
Pecos County, Texas	Southern Delaware Basin (Wolfcamp)
Other Texas Gulf Coast	Conventional and smaller unconventional formations
Zavala and Dimmit counties, Texas	Buda / Eagle Ford
Weston County, Wyoming	Muddy Sandstone
Sublette County, Wyoming	Jonah Field (1)

(1) Through a 37% equity investment in Exaro Energy III LLC (“Exaro”). Production associated with this investment is not included in the Company’s reported production results for the three and six months ended June 30, 2018.

The Company’s 2018 capital program has focused on the development of the Company’s 16,500 gross (6,800 net) acres in the Southern Delaware Basin. Additionally, the Company will continue to identify opportunities for cost efficiencies in all areas of its operations, maintain core leases and continue to identify new resource potential opportunities internally and, where appropriate and assuming the Company has adequate capital to do so, through acquisition. Acquisition efforts will typically be focused on areas in which the Company can leverage its geological and operational experience and expertise to exploit identified drilling opportunities and where the Company can develop an inventory of additional drilling prospects that the Company believes will enable it to economically grow production and add reserves. The Company continuously monitors the commodity price environment, including its stability, forecast and geographic price differentials, and, if warranted, makes adjustments to its strategy as the year progresses.

2. Summary of Significant Accounting Policies

The accounting policies followed by the Company are set forth in the notes to the Company's audited consolidated financial statements included in its Annual Report on Form 10-K for the year ended December 31, 2017 (the "2017 Form 10-K") filed with the Securities and Exchange Commission ("SEC"). Please refer to the notes to the financial statements included in the 2017 Form 10-K for additional details of the Company's financial condition, results of operations and cash flows. No material items included in those notes have changed except as a result of normal transactions in the interim or as disclosed within this report.

Basis of Presentation

The accompanying unaudited consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information, pursuant to the rules and regulations of the SEC, including instructions to Quarterly Reports on Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by GAAP for complete annual financial statements. In the opinion of management, all adjustments considered necessary for a fair statement of the unaudited consolidated financial statements have been included. All such adjustments are of a normal recurring nature. The consolidated financial statements should be read in conjunction with the 2017 Form 10-K. The consolidated results of operations for the six months ended June 30, 2018 are not necessarily indicative of the results that may be expected for the year ending December 31, 2018.

Table of Contents

The Company’s consolidated financial statements include the accounts of Contango Oil & Gas Company and its subsidiaries, after elimination of all material intercompany balances and transactions. All wholly owned subsidiaries are consolidated. The investment in Exaro by the Company’s wholly owned subsidiary, Contaro Company (“Contaro”), is accounted for using the equity method of accounting, and therefore, the Company does not include its share of individual operating results, reserves or production in those reported for the Company’s consolidated results.

Oil and Gas Properties - Successful Efforts

The Company’s application of the successful efforts method of accounting for the Company’s natural gas and oil exploration and production activities requires judgments as to whether particular wells are developmental or exploratory, since exploratory costs and the costs related to exploratory wells that are determined to not have proved reserves must be expensed whereas developmental costs are capitalized. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver natural gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within a productive natural gas and oil field are typically treated as development costs and capitalized, but often these seismic programs extend beyond the proved reserve areas, and therefore, management must estimate the portion of seismic costs to expense as exploratory. The evaluation of natural gas and oil leasehold acquisition costs included in unproved properties requires management's judgment of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

Impairment of Long-Lived Assets

Pursuant to GAAP, when circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future cash flows on a field by field basis to the unamortized capitalized cost of the asset. If the estimated future undiscounted cash flows based on the Company’s estimate of future reserves, natural gas and oil prices, operating costs and production levels from oil and natural gas reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair value. The factors used to determine fair value include, but are not limited to, estimates of proved, probable and possible reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Additionally, the Company may use appropriate market data to determine fair value. The Company recognized $2.7 million in non-cash proved property impairment charges for the six months ended June 30, 2018, including a $2.3 million impairment related to its Vermilion 170 offshore property during the three months ended March 31, 2018 and a $0.4 million impairment related to non-core onshore properties due to revised estimated reserves during the three months ended June 30, 2018. No impairment of proved properties was recognized during the three and six months ended June 30, 2017.

Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. The Company recognized impairment expense of approximately $0.4 million and approximately $1.2 million for the three and six months ended June 30, 2018, respectively, related to impairment of certain non-core unproved properties primarily due to expiring leases. The Company also recognized $1.4 million in impairment expense for the three and six months ended June 30, 2017 related to the partial impairment of two unused offshore platforms that were subsequently sold.

Net Loss Per Common Share

Basic net loss per common share is computed by dividing the net loss attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net loss per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. Potentially dilutive securities, including unexercised stock options, Performance Stock Units and unvested restricted stock, have not been considered when their effect would be antidilutive. For the three months ended June 30, 2018, the Company excluded 1,133,534 potentially dilutive securities, as they were antidilutive, and excluded 1,197,029 potentially dilutive securities for the six months ended June 30, 2018, as they were antidilutive. For the three months ended June 30, 2017, the Company excluded 1,366,091 potentially dilutive securities, as they were antidilutive, and excluded 1,367,242 potentially dilutive securities for the six months ended June 30, 2017, as they were antidilutive.

Table of Contents

Subsidiary Guarantees

Contango Oil & Gas Company, as the parent company (the “Parent Company”), has filed a registration statement on Form S-3 with the SEC to register, among other securities, debt securities that the Parent Company may issue from time to time. Any such debt securities would likely be guaranteed on a full and unconditional basis by each of the Company’s current subsidiaries and any future subsidiaries specified in any future prospectus supplement (each a “Subsidiary Guarantor”). Each of the Subsidiary Guarantors is wholly owned by the Parent Company, either directly or indirectly. The Parent Company has no assets or operations independent of the Subsidiary Guarantors, and there are no significant restrictions upon the ability of the Subsidiary Guarantors to distribute funds to the Parent Company. The Parent Company has one wholly owned subsidiary that is inactive and not a Subsidiary Guarantor. The Parent Company’s wholly owned subsidiaries do not have restricted assets that exceed 25% of net assets as of the most recent fiscal year end that may not be transferred to the Parent Company in the form of loans, advances or cash dividends by such subsidiary without the consent of a third party.

Revenue Recognition

Adoption of ASC 606

As of January 1, 2018 the Company adopted Accounting Standards Codification 606 – Revenue from Contracts with Customers (“ASC 606”). The Company adopted ASC 606 using the modified retrospective method which allows the Company to apply the new standard to all new contracts entered into after December 31, 2017 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance prior to December 31, 2017. The Company identified no material impact on its historical revenues upon initial application of ASC 606, and as such has not recognized any cumulative catch-up effect to the opening balance of the Company’s shareholders’ equity as of January 1, 2018. ASC 606 supersedes previous revenue recognition requirements in ASC 605 and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services.

Revenue from Contracts with Customers

Sales of oil, condensate, natural gas and natural gas liquids (“NGLs”) are recognized at the time control of the products are transferred to the customer. Based upon the Company’s current purchasers’ past experience and expertise in the market, collectability is probable, and there have not been payment issues with the Company’s purchasers over the past year or currently. Generally, the Company’s gas processing and purchase agreements indicate that the processors take control of the gas at the inlet of the plant and that control of residue gas is returned to the Company at the outlet of the plant. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of NGLs. The Company delivers oil and condensate to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title and risk of loss of the product.

When sales volumes exceed the Company's entitled share, a production imbalance occurs. If production imbalance exceeds the Company's share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. Production imbalances have not had and currently do not have a material impact on the financial statements, and this did not change with the adoption of ASC 606.

Transaction Price Allocated to Remaining Performance Obligations

Generally, the Company's contracts have an initial term of one year or longer but continue month to month unless written notification of termination in a specified time period is provided by either party to the contract. The Company has used the practical expedient in ASC 606 which states that the Company is not required to disclose that transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligation is not required.

Contract Balances

The Company receives purchaser statements from the majority of the Company's customers but there are a few contracts where the Company prepares the invoice. Payment is unconditional upon receipt of the statement or invoice.

Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities under ASC 606. The majority of the Company's contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and supply and demand conditions. The price of these commodities fluctuates to remain competitive with supply.

Prior Period Performance Obligations

The Company records revenue in the month production is delivered to the purchaser. Settlement statements may not be received for 30 to 90 days after the date production is delivered, and therefore the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. Differences between the Company's estimates and the actual amounts received for product sales are generally recorded in the following month that payment is received. Any differences between the Company's revenue estimates and actual revenue received historically have not been significant. The Company has internal controls in place for its revenue estimation accrual process.

Impact of Adoption of ASC 606

The Company has reviewed all of the Company's natural gas, NGLs, residue gas, condensate and crude oil sales contracts to assess the impact of the provisions of ASC 606. Based upon the Company's review, there were no required changes to the recording of residue gas or condensate and crude oil contracts. Certain NGL and natural gas contracts would require insignificant changes to the recording of transportation, gathering and processing fees as net to revenue or as an expense. The Company concluded that these minor changes were not material to its operating results on a quantitative or qualitative basis. Therefore, there was no impact to the Company's operating results for the six months ended June 30, 2018. The Company has modified procedures to its existing internal controls relating to revenue by reviewing for any significant increase in sales level, primarily on gas processing or gas purchasing contracts, on a quarterly basis to monitor the significance of gross revenue versus net revenue and expenses under ASC 606. As under previous revenue guidance, the Company will continue to review all new or modified revenue contracts on a quarterly basis for proper treatment.

Recent Accounting Pronouncements

In January 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2018-01 – Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842. The amendments in this update permit an entity to elect an optional transition practical expedient to not evaluate under Topic 842 land easements (right of way payments) that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840. Right of way payments do not have a material impact on the Company's results of operations and the Company plans to elect the practical expedient to evaluate right of way payments prospectively on adoption of Topic 842.

In February 2016, the FASB issued ASU No. 2016-02: Leases (Topic 842) (ASU 2016 02). The main objective of ASU 2016-02 is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous GAAP and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases. ASU 2016-02 requires lessees to recognize assets and liabilities arising from leases on the balance sheet. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. For public entities, ASU 2016-02 is effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years; early application is permitted. The Company is currently collating all leases and potential leases for evaluation and will continue to assess the impact this may have on its financial position, results of operations and cash flows.

3. Acquisitions and Dispositions

On May 25, 2018, the Company sold its non-operated assets located in Starr County, Texas for a cash purchase price of $0.6 million. The Company recorded a gain of $1.4 million after removal of the asset retirement obligations associated with the sold properties.

Table of Contents

On March 28, 2018, the Company sold its operated Eagle Ford Shale assets located in Karnes County, Texas for a cash purchase price of $21.0 million. The Company recorded a net gain of $9.4 million.

Effective February 1, 2017, the Company sold to a third party all of its assets in the Bob West North area and its operated assets in the Escobas area, both located in Southeast Texas, for a cash purchase price of $650,000. The Company recorded a net gain of $2.9 million after removal of the asset retirement obligations associated with the sold properties.

4. Fair Value Measurements

Pursuant to Accounting Standards Codification 820, Fair Value Measurements and Disclosures (ASC 820), the Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

The following table sets forth, by level within the fair value hierarchy, the Company’s financial assets and liabilities that were accounted for at fair value as of June 30, 2018. As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have been no transfers between Level 1, Level 2 or Level 3.

Fair value information for financial assets and liabilities was as follows as of June 30, 2018 (in thousands):

	Total	Fair Value Measurements Using		
	Carrying Value	Level 1	Level 2	Level 3
Derivatives				

Commodity price contracts - assets	$ 313	$ —	$ 313	$ —
Commodity price contracts - liabilities	$ (3,866)	$ —	$ (3,866)	$ —

Derivatives listed above are recorded in “Current derivative asset or liability” and “Long-term derivative asset or liability” on the Company’s consolidated balance sheet and include swaps and costless collars that are carried at fair value. The Company records the net change in the fair value of these positions in "Gain (loss) on derivatives, net" in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted market prices and implied volatility factors related to changes in the forward curves. See Note 5 - "Derivative Instruments" for additional discussion of derivatives.

As of June 30, 2018, the Company's derivative contracts were with certain members of its credit facility lending group, which are major financial institutions with investment grade credit ratings which are believed to have minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate such nonperformance.

Estimates of the fair value of financial instruments are made in accordance with the requirements of ASC 825, Financial Instruments. The estimated fair value amounts are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company's credit facility with the Royal Bank of Canada and other lenders (the “RBC

Table of Contents

Credit Facility”) approximates carrying value because the facility interest rate approximates current market rates and is reset at least every six months. See Note 9 - "Long-Term Debt" for further information.

Impairments

Contango tests proved oil and natural gas properties for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. The Company estimates the undiscounted future cash flows expected in connection with the oil and gas properties on a field by field basis and compares such future cash flows to the unamortized capitalized costs of the properties. If the estimated future undiscounted cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to its fair value. The factors used to determine fair value include, but are not limited to, estimates of proved, probable and possible reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Additionally, the Company may use appropriate market data to determine fair value. Because these significant fair value inputs are typically not observable, impairments of long-lived assets are classified as a Level 3 fair value measure.

Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period.

Asset Retirement Obligations

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. The factors used to determine fair value include, but are not limited to, estimated future plugging and abandonment costs and expected lives of the related reserves. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3.

5. Derivative Instruments

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk. Derivative contracts are typically utilized to hedge the Company's exposure to price fluctuations and reduce the variability in the Company's cash flows associated with anticipated sales of future oil and natural gas production. The Company typically hedges a substantial, but varying, portion of anticipated oil and natural gas production for future periods. The Company believes that these derivative arrangements, although not free of risk, allow it to achieve a more predictable cash flow and to reduce exposure to commodity price fluctuations. However, derivative arrangements limit the benefit of increases in the prices of crude oil, natural gas and natural gas liquids sales. Moreover, because its derivative arrangements apply only to a portion of its production, the Company’s strategy provides only partial protection against declines in commodity prices. Such arrangements may expose the Company to risk of financial loss in certain circumstances. The Company continuously reevaluates its hedging programs in light of changes in production, market conditions and commodity price forecasts.

As of June 30, 2018, the Company’s natural gas and oil derivative positions consisted of “swaps” and “costless collars”. Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. A costless collar consists of a purchased put option and a sold call option, which establishes a minimum and maximum price, respectively, that the Company will receive for the volumes under the contract.

It is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy institutions deemed by management as competent and competitive market makers. The Company does not post collateral, nor is it exposed to potential margin calls, under any of these contracts, as they are secured under the RBC Credit Facility. See Note 9 - "Long-Term Debt" for further information regarding the RBC Credit Facility.

The Company has elected not to designate any of its derivative contracts for hedge accounting. Accordingly, derivatives are carried at fair value on the consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs. The Company

Table of Contents

records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in "Gain (loss) on derivatives, net" on the consolidated statements of operations.

As of June 30, 2018, the following derivative instruments were in place (fair value in thousands):

Commodity	Period	Derivative	Volume/Month	Price/Unit	Fair Value
Natural Gas	July 2018	Swap	370,000 MMBtus	$ 3.07 (1)	27
Natural Gas	Aug 2018 - Oct 2018	Swap	70,000 MMBtus	$ 3.07 (1)	34
Natural Gas	Nov 2018 - Dec 2018	Swap	320,000 MMBtus	$ 3.07 (1)	45
Oil	July 2018 - Oct 2018	Collar	20,000 Bbls	$ 52.00 - 56.85 (2)	(1,466)
Oil	Nov 2018 - Dec 2018	Collar	15,000 Bbls	$ 52.00 - 56.85 (2)	(484)
Oil	July 2018 - Dec 2018	Collar	2,000 Bbls	$ 52.00 - 58.76 (3)	(149)
Oil	July 2018	Collar	6,000 Bbls	$ 58.00 - 68.00 (2)	(54)
Oil	Nov 2018 - Dec 2018	Collar	5,000 Bbls	$ 58.00 - 68.00 (2)	(68)
Oil	July 2018	Swap	6,000 Bbls	$ 70.11 (3)	(21)
Oil	Aug 2018 - Oct 2018	Swap	3,000 Bbls	$ 70.11 (3)	(7)
Oil	Nov 2018 - Dec 2018	Swap	6,000 Bbls	$ 70.11 (3)	14
Oil	Jan 2019 - Dec 2019	Collar	4,000 Bbls	$ 52.00 - 59.45 (3)	(373)
Oil	Jan 2019 - Dec 2019	Collar	7,000 Bbls	$ 50.00 - 58.00 (2)	(1,037)
Oil	Jan 2019 - July 2019	Swap	6,000 Bbls	$ 66.10 (3)	(14)
		Total net fair value of derivative instruments			$ (3,553)

(1) Based on Henry Hub NYMEX natural gas prices.
(2) Based on Argus Louisiana Light Sweet crude oil prices.
(3) Based on West Texas Intermediate crude oil prices.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of June 30, 2018 (in thousands):

Gross	Netting (1)	Total

Assets	$ 313	$ —	$ 313
Liabilities	$ (3,866)	$ —	$ (3,866)

(1) Represents counterparty netting under agreements governing such derivatives.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of December 31, 2017 (in thousands):

	Gross	Netting (1)	Total
Assets	$ 1,188	$ (1,188)	$ —
Liabilities	$ (2,431)	$ 1,188	$ (1,243)

(1) Represents counterparty netting under agreements governing such derivatives.

13

Table of Contents

The following table summarizes the effect of derivative contracts on the consolidated statements of operations for the three and six months ended June 30, 2018 and 2017 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Crude oil contracts	$ (1,123)	$ 367	$ (1,711)	$ 537
Natural gas contracts	305	68	380	(281)
Realized gain (loss)	$ (818)	$ 435	$ (1,331)	$ 256
Crude oil contracts	$ (1,311)	$ 293	$ (1,594)	$ 817
Natural gas contracts	(481)	759	(717)	3,510
Unrealized gain (loss)	$ (1,792)	$ 1,052	$ (2,311)	$ 4,327
Gain (loss) on derivatives, net	$ (2,610)	$ 1,487	$ (3,642)	$ 4,583

6. Stock-Based Compensation

The Company recognized approximately $3.0 million and $3.1 million in stock compensation expense during the six months ended June 30, 2018 and 2017, respectively, for equity awards granted to its officers, employees and directors. As of June 30, 2018, an additional $4.7 million of compensation expense remained to be recognized over the remaining weighted-average vesting period of 1.7 years. This includes expense related to restricted stock, Performance Stock Units (“PSUs”) and stock options.

Restricted Stock

During the six months ended June 30, 2018, the Company granted 225,782 shares of restricted common stock, which vest over three years, to executive officers as part of their overall compensation package. Additionally, the Company granted 82,500 shares of restricted common stock, which vest over one year, to directors pursuant to the Company’s Director Compensation Plan. The weighted average fair value of the restricted shares granted during the six months ended June 30, 2018, was $3.76 with a total fair value of approximately $1.2 million with no adjustment for an estimated weighted average forfeiture rate. During the six months ended June 30, 2018, 24,980 restricted shares were forfeited by former employees. The aggregate intrinsic value of restricted shares forfeited during the six months ended June 30, 2018 was approximately $222 thousand. Approximately 1.2 million shares remained available for grant under the Amended and Restated 2009 Incentive Compensation Plan as of June 30, 2018, assuming PSUs are settled at 100% of target.

During the six months ended June 30, 2017, the Company granted 43,000 shares of restricted common stock, which vest over three years, to newly hired employees as part of their overall compensation package. Additionally, the Company granted 338,076 shares of restricted stock to existing employees, which vest over three years, as part of their overall compensation package, and 74,325 shares of restricted common stock, which vest over one year, to directors pursuant to the Company's Director Compensation Plan. The weighted average fair value of the restricted shares granted during the six months ended June 30, 2017, was $7.56 with a total fair value of approximately $3.4 million after adjustment for an estimated weighted average forfeiture rate of 5.7%. During the six months ended June 30, 2017, 63,490 restricted shares were forfeited by former employees. The aggregate intrinsic value of restricted shares forfeited during the six months ended June 30, 2017 was approximately $688 thousand.

Performance Stock Units

During the six months ended June 30, 2018, the Company granted 190,782 PSUs to executive officers as part of their overall compensation package, at a weighted average fair value of $7.69 per unit. During the six months ended June 30, 2017, the Company granted 30,000 PSUs to a new employee, at a weighted average fair value of $8.32 per unit. An additional 160,908 PSUs were granted to executive officers, as part of their overall compensation package, at a value of $13.91 per unit during the six months ended June 30, 2017. All fair value prices were determined using the Monte Carlo simulation model. During the six months ended June 30, 2018 and 2017, 19,300 and 34,899 PSUs were forfeited by former employees, respectively. PSUs represent the opportunity to receive shares of the Company's common stock at the time of settlement. The number of shares to be awarded upon settlement of these PSUs may range from 0% to 300% of the number of PSUs awarded contingent upon the achievement of certain share price appreciation targets as compared to a peer group index. The PSUs vest and settlement is determined after a three year period.

Compensation expense associated with PSUs is based on the grant date fair value of a single PSU as determined using the Monte Carlo simulation model which utilizes a stochastic process to create a range of potential future outcomes given a variety of inputs. As it is contemplated that the PSUs will be settled with shares of the Company's common stock after three years, the PSU awards are accounted for as equity awards, and the fair value is calculated on the grant date. The simulation model calculates the payout percentage based on the stock price performance over the performance period. The concluded fair value is based on the average achievement percentage over all the iterations. The resulting fair value expense is amortized over the life of the PSU award.

Stock Options

Under the fair value method of accounting for stock options, cash flows from the exercise of stock options resulting from tax benefits in excess of recognized cumulative compensation cost (excess tax benefits) are classified as financing cash flows. For the six months ended June 30, 2018 and 2017, there was no excess tax benefit recognized.

Compensation expense related to stock option grants are recognized over the stock option’s vesting period based on the fair value at the date the options are granted. The fair value of each option is estimated as of the date of grant using the Black-Scholes options-pricing model. No stock options were granted during the six months ended June 30, 2018 or 2017.

During the six months ended June 30, 2018, no stock options were exercised or forfeited. During the six months ended June 30, 2017, no stock options were exercised and stock options for 14,586 shares of common stock were forfeited by former employees.

7. Other Financial Information

The following table provides additional detail for accounts receivable, prepaid expenses and other, and accounts payable and accrued liabilities which are presented on the consolidated balance sheets (in thousands):

	June 30, 2018	December 31, 2017

Accounts receivable:		
Trade receivables	$ 5,316	$ 6,565
Receivable for Alta Resources Distribution	1,993	1,993
Joint interest billings	3,887	4,030
Income taxes receivable	424	424
Other receivables	88	828
Allowance for doubtful accounts	(781)	(781)
Total accounts receivable	$ 10,927	$ 13,059
Prepaid expenses and other:		
Prepaid insurance	$ 920	$ 1,177
Other	620	715
Total prepaid expenses and other	$ 1,540	$ 1,892
Accounts payable and accrued liabilities:		
Royalties and revenue payable	$ 18,888	$ 18,181
Advances from partners	4,145	2,243
Accrued exploration and development	8,171	8,400
Trade payables	4,726	9,559
Accrued general and administrative expenses	2,322	2,960
Accrued operating expenses	1,662	1,654
Other accounts payable and accrued liabilities	2,197	3,758
Total accounts payable and accrued liabilities	$ 42,111	$ 46,755

Table of Contents

Included in the table below is supplemental cash flow disclosures and non-cash investing activities during the six months ended June 30, 2018 and 2017 (in thousands):

	Six Months Ended June 30,	
	2018	2017
Cash payments:		
Interest payments	$ 2,596	$ 1,491
Income tax payments	$ 81	$ 498
Non-cash investing activities in the consolidated statements of cash flows:		
Decrease in accrued capital expenditures	$ (229)	$ (7,935)

8. Investment in Exaro Energy III LLC

The Company maintains an ownership interest in Exaro of approximately 37%.

The following table (in thousands) presents unaudited condensed balance sheet data for Exaro as of June 30, 2018 and December 31, 2017. The balance sheet data was derived from Exaro’s balance sheet as of June 30, 2018 and December 31, 2017 and was not adjusted to represent the Company’s percentage of ownership interest in Exaro. The Company’s share in the equity of Exaro at June 30, 2018 was approximately $18.6 million.

	June 30, 2018	December 31, 2017
Current assets (1)	$ 12,910	$ 17,063
Non-current assets:		
Net property and equipment	77,837	82,450
Gas processing deposit	1,150	1,150
Other non-current assets	445	390
Total non-current assets	79,432	83,990
Total assets	$ 92,342	$ 101,053
Current liabilities	$ 4,415	$ 6,199
Non-current liabilities:		
Long-term debt	32,411	40,375
Other non-current liabilities	3,958	3,858
Total non-current liabilities	36,369	44,233
Members' equity	51,558	50,621

Total liabilities & members' equity	$ 92,342	$ 101,053

(1) Approximately $9.6 million and $12.8 million of current assets as of June 30, 2018 and December 31, 2017, respectively, is cash.

16

Table of Contents

The following table (in thousands) presents the unaudited condensed results of operations for Exaro for the three and six months ended June 30, 2018 and 2017. The results of operations for the three and six months ended June 30, 2018 and 2017 were derived from Exaro's financial statements for the respective periods. The income statement data below was not adjusted to represent the Company's ownership interest but rather reflects the results of Exaro as a company. The Company's share in Exaro's results of operations recognized for the three months ended June 30, 2018 and 2017 was a loss of $0.5 million, net of no tax expense, and a gain of $0.2 million, net of no tax expense, respectively. The Company's share in Exaro's results of operations recognized for the six months ended June 30, 2018 and 2017 was a gain of $0.2 million, net of no tax expense, and a gain of $2.0 million, net of no tax expense, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Production:				
Oil (thousand barrels)	21	28	43	54
Gas (million cubic feet)	1,946	2,272	3,881	4,580
Total (million cubic feet equivalent)	2,072	2,442	4,139	4,902
Oil and natural gas sales	$ 5,955	$ 7,844	$ 12,838	$ 17,016
Gain (loss) on derivatives	(582)	841	1,044	3,402
Less:				
Lease operating expenses	3,278	4,767	6,668	7,987
Depreciation, depletion, amortization & accretion	2,321	2,249	4,729	4,591
General & administrative expense	351	874	705	1,606
Income (loss) from continuing operations	(577)	795	1,780	6,234
Net interest expense	(636)	(328)	(1,079)	(952)
Net income (loss)	$ (1,213)	$ 467	$ 701	$ 5,282

Exaro's results of operations do not include income taxes because Exaro is treated as a partnership for tax purposes.

9. Long-Term Debt

RBC Credit Facility

In October 2013, the Company entered into a $500 million revolving credit facility with Royal Bank of Canada and other lenders (the "RBC Credit Facility"), the maturity of which has been extended by subsequent amendment to October 1, 2019. The borrowing base under the facility is redetermined each November and May. As of June 30, 2018, the borrowing base under the RBC Credit Facility was $110 million, but was reduced to $105 million effective August 1, 2018, as agreed to during the May 2018 redetermination.

As of June 30, 2018, the Company had approximately $80.8 million outstanding under the RBC Credit Facility and $1.9 million in outstanding letters of credit. As of December 31, 2017, the Company had approximately $85.4 million outstanding under the RBC Credit Facility and $1.9 million in outstanding letters of credit. As of June 30, 2018, borrowing availability under the RBC Credit Facility was $27.3 million.

The RBC Credit Facility is collateralized by a lien on substantially all the producing assets of the Company and its subsidiaries, including a security interest in the stock of Contango's subsidiaries and a lien on the Company's oil and gas properties.

Total interest expense under the RBC Credit Facility, including commitment fees, for the three and six months ended June 30, 2018 was approximately $1.3 million and $2.7 million, respectively. Total interest expense under the RBC Credit Facility, including commitment fees, for the three and six months ended June 30, 2017 was approximately $0.9 million and $1.7 million, respectively.

The RBC Credit Facility contains restrictive covenants which, among other things, restrict the declaration or payment of dividends by Contango and require a Current Ratio of greater than or equal to 1.0 and a Leverage Ratio of less than or equal to 3.50, both as defined in the RBC Credit Facility Agreement. As of June 30, 2018, the Company was

Table of Contents

in compliance with all but the Current Ratio covenant under the RBC Credit Facility, although the Company obtained a waiver for such non-compliance effective as of June 30, 2018. The Company intends to review the amount and timing of its remaining 2018 capital expenditure program after the drilling of its next three Southern Delaware Basin wells. The Company's ability or commitment to continue its capital expenditure program will be determined based on its evaluation of well results, commodity prices (including the impact of the dramatic increase in the Midland-Cushing oil price differentials) and the availability of capital. The RBC Credit Facility contains events of default that may accelerate repayment of any borrowings and/or termination of the facility. Events of default include, but are not limited to, payment defaults, breach of certain covenants including the current ratio covenant, bankruptcy, insolvency or change of control events.

The weighted average interest rate in effect at June 30, 2018 and December 31, 2017 was 5.8% and 5.2%, respectively. The RBC Credit Facility matures on October 1, 2019, at which time any outstanding balances will be due.

10. Income Taxes

The Company's income tax provision for continuing operations consists of the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Current tax provision:				
Federal	$ —	$ —	$ —	$ —
State	151	118	309	309
Total	$ 151	$ 118	$ 309	$ 309
Total tax provision:				
Federal	$ —	$ —	$ —	$ —
State	151	118	309	309
Total income tax provision	$ 151	$ 118	$ 309	$ 309

In recording deferred income tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred income tax assets will be realized. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. The Company believes that after considering all the available objective evidence, both positive and negative, historical and prospective, with greater weight given to historical evidence, management is not able to determine that it is more likely than not that the deferred tax assets will be realized and, therefore, established a full valuation allowance at September 30, 2015. For the six months ended June 30, 2018, the Company continues to take a full valuation allowance against its deferred tax asset except for the portion attributable to the estimated refundable Alternative Minimum Tax ("AMT") credit. The Company will continue to assess the valuation allowance against deferred tax assets considering all available information obtained in future reporting periods.

On December 22, 2017, the United States enacted tax reform legislation known as the H.R.1, commonly referred to as the “Tax Cuts and Jobs Act” (the “Act”), resulting in significant modifications to existing law. The Company completed the accounting for the effects of the Act during 2017. The Company’s financial statements for the six months ended June 30, 2018 reflect certain effects of the Act which includes the reduced corporate tax of 21%, elimination of the corporate AMT, limitations on the use of interest expense and net operating losses, accelerated expensing of tangible property, as well as other changes.

11. Commitments and Contingencies

Legal Proceedings

From time to time, the Company is involved in legal proceedings relating to claims associated with its properties, operations or business or arising from disputes with vendors in the normal course of business, including the material matters discussed below.

In November 2010, a subsidiary of the Company, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in two wells that has not been recognized by the Company or by predecessor operators to which the

Table of Contents

Company had granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decade-old poorly documented transactions. Based on prior summary judgments, the trial court has entered a final judgment in the case in favor of the plaintiffs for approximately $5.3 million, plus post-judgment interest. The Company appealed the trial court's decision to the applicable state Court of Appeals. In the fourth quarter of 2017, the Court of Appeals issued its opinion and affirmed the trial court's summary decision. The Company previously filed a motion for rehearing with the Court of Appeals, which was recently denied, as expected. The Company continues to vigorously defend this lawsuit and is currently preparing a petition requesting a review by the Texas Supreme Court. In addition, the Company is also in the process of seeking amicus briefs from industry associations whose members would be affected the by the Court of Appeals' ruling.

In September 2012, a subsidiary of the Company was named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by the Company in the Catherine Henderson "A" Unit in Liberty County in Texas. This case was subsequently transferred to the District Court for Liberty County, Texas and combined with a suit filed by other parties against the plaintiff claiming ownership of the disputed interest. The plaintiff has alleged that, based on its interpretation of a series of 1972 deeds, it owns an additional 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid (this claimed interest is in addition to a 1/16th unleased mineral interest on which it has been paid). The Company has made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained the disputed mineral interests thereunder. The plaintiff previously alleged damages of approximately $10.7 million although the plaintiff's claim increases as additional hydrocarbons are produced from the subject wells. The trial court has entered judgment in favor of the Company's subsidiary and the successors to the grantors under the aforementioned deeds. The plaintiff appealed the trial court's decision to the applicable state Court of Appeals. On December 14, 2017, the Court of Appeals affirmed the judgment in the Company's favor. The plaintiff filed a motion for rehearing, which was denied in May 2018. The plaintiff has indicated that it intends to file a petition requesting that the matter be reviewed by the Texas Supreme Court. The Company continues to vigorously defend this lawsuit and believes that it has meritorious defenses. The Company believes if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights the Company may have against other working interest and/or royalty interest owners in the unit.

While many of these matters involve inherent uncertainty and the Company is unable at the date of this filing to estimate an amount of possible loss with respect to certain of these matters, the Company believes that the amount of the liability, if any, ultimately incurred with respect to these proceedings or claims will not have a material adverse effect on its consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company maintains various insurance policies that may provide coverage when certain types of legal proceedings are determined adversely.

Throughput Contract Commitment

The Company signed a throughput agreement with a third party pipeline owner/operator that constructed a natural gas gathering pipeline in the Company's Southeast Texas area that allows the Company to defray the cost of building the pipeline itself. The Company currently forecasts that monthly gas volume deliveries through this line in its Southeast Texas area will not meet minimum throughput requirements under the agreement. Without further development in that area, the volume deficiency will continue through the expiration of the throughput commitment in March 2020. The throughput deficiency fee is paid in April of each calendar year. As of June 30, 2018, the Company estimates that the net deficiency fee will be approximately $1.0 million annually for the remaining contract period, based upon forecasted production volumes from existing proved producing reserves only, assuming no future development during this commitment period. As of June 30, 2018, based upon the current commodity price market and the Company's short term strategic drilling plans, the Company has recorded a $0.7 million loss contingency through December 31, 2018. The Company will assess this commitment in the fourth quarter when its development plans for this area are addressed in the approved budget for 2019.

Table of Contents

Available Information

General information about us can be found on our website at www.contango.com. Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file or furnish them to the Securities and Exchange Commission ("SEC"). We are not including the information on our website as a part of, or incorporating it by reference into, this Report.

Cautionary Statement about Forward-Looking Statements

Certain statements contained in this report may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, and Section 21E of the Securities Exchange Act of 1934, as amended. The words and phrases "should be", "will be", "believe", "expect", "anticipate", "estimate", "forecast", "goal" and similar expressions ide forward-looking statements and express our expectations about future events. Although we believe the expectations reflected in such forward-looking statements are reasonable, such expectations may not occur. These forward-looking statements are made subject to certain risks and uncertainties that could cause actual results to differ materially from those stated. Risks and uncertainties that could cause or contribute to such differences include, without limitation, those discussed in the section entitled "Risk Factors" included in our Annual Report on Form 10-K and Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 and those factors summarized below:

- our ability to successfully develop our undeveloped acreage in the Southern Delaware Basin and realize the benefits associated therewith;
- our financial position;
- our business strategy, including outsourcing;
- meeting our forecasts and budgets;
- expectations regarding natural gas and oil markets in the United States;
- volatility in natural gas, natural gas liquids and oil prices, including regional differentials;
- operational constraints, start-up delays and production shut-ins at both operated and non-operated production platforms, pipelines and natural gas processing facilities;
- the risks associated with acting as operator of deep high pressure and high temperature wells, including well blowouts and explosions;
- the risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry holes, especially in prospects in which we have made a large capital commitment relative to the size of our capitalization structure;
- the timing and successful drilling and completion of natural gas and oil wells;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations, and fund our drilling program;
- the cost and availability of rigs and other materials, services and operating equipment;
- timely and full receipt of sale proceeds from the sale of our production;

- the ability to find, acquire, market, develop and produce new natural gas and oil properties;
- interest rate volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- the need to take impairments on our properties due to lower commodity prices;
- the ability to post additional collateral for current bonds or comply with new supplemental bonding requirements imposed by the Bureau of Ocean Energy Management;
- operating hazards attendant to the natural gas and oil business including weather, environmental risks, accidental spills, blowouts and pipeline ruptures, and other risks;
  - downhole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells, production facilities, processing plants or pipeline mishaps;
- actions or inactions of third-party operators of our properties;
- actions or inactions of third-party operators of pipelines or processing facilities;
- the ability to retain key members of senior management and key technical employees and to find and retain skilled personnel;

Table of Contents

- strength and financial resources of competitors;
- federal and state legislative and regulatory developments and approvals (including additional taxes and changes in environmental regulations);
- worldwide economic conditions;
- the ability to construct and operate infrastructure, including pipeline and production facilities;
- the continued compliance by us with various pipeline and gas processing plant specifications for the gas and condensate produced by us;
- operating costs, production rates and ultimate reserve recoveries of our natural gas and oil discoveries;
- expanded rigorous monitoring and testing requirements; and
- the ability to obtain adequate insurance coverage on commercially reasonable terms.

Any of these factors and other factors described in this report could cause our actual results to differ materially from the results implied by these or any other forward-looking statements made by us or on our behalf. Although we believe our estimates and assumptions to be reasonable when made, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. Our assumptions about future events may prove to be inaccurate. We caution you that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure you that those statements will be realized or the forward-looking events and circumstances will occur. All forward-looking statements speak only as of the date of this report.

We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as required by law. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

You should not unduly rely on these forward-looking statements in this report, as they speak only as of the date of this report. Except as required by law, we undertake no obligation to publicly release any revisions to these forward-looking statements to reflect events or circumstances occurring after the date of this report or to reflect the occurrence of unanticipated events.

Table of Contents

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the consolidated financial statements and the accompanying notes and other information included elsewhere in this Quarterly Report on Form 10-Q and in our 2017 Form 10-K, previously filed with the Securities and Exchange Commission ("SEC").

Overview

We are a Houston, Texas based, independent oil and natural gas company. Our business is to maximize production and cash flow from our offshore properties in the shallow waters of the Gulf of Mexico (“GOM”) and onshore Texas and Wyoming properties and to use that cash flow to explore, develop, exploit, increase production from and acquire crude oil and natural gas properties in West Texas, the onshore Texas Gulf Coast and the Rocky Mountain regions of the United States.

The following table lists our primary producing areas as of June 30, 2018:

Location	Formation
Gulf of Mexico	Offshore Louisiana - water depths less than 300 feet
Madison and Grimes counties, Texas	Woodbine (Upper Lewisville)
Pecos County, Texas	Southern Delaware Basin (Wolfcamp)
Other Texas Gulf Coast	Conventional and smaller unconventional formations
Zavala and Dimmit counties, Texas	Buda / Eagle Ford
Weston County, Wyoming	Muddy Sandstone
Sublette County, Wyoming	Jonah Field (1)

(1) Through a 37% equity investment in Exaro Energy III LLC (“Exaro”). Production associated with this investment is not included in our reported production results for the three and six months ended June 30, 2018.

Our 2018 capital program has focused on the development of our 16,500 gross (6,800 net) acres in the Southern Delaware Basin. Additionally, we will continue to identify opportunities for cost efficiencies in all areas of our operations, maintain core leases and continue to identify new resource potential opportunities internally and, where appropriate and assuming we have adequate capital to do so, through acquisition. Acquisition efforts will typically be focused on areas in which we can leverage our geological and operational experience and expertise to exploit identified drilling opportunities and where we can develop an inventory of additional drilling prospects that we believe will enable us to economically grow production and add reserves. We continuously monitor the commodity price environment, including its stability, forecast and geographic price differentials, and, if warranted, make adjustments to our strategy as the year progresses.

Capital Expenditures

Our Southern Delaware Basin acreage has generated, and is expected to continue to generate, positive returns on our drilling investment in the current commodity price environment. We currently expect to drill three wells and complete two for the remainder of the year, after which we intend to review the amount and timing of our remaining 2018 capital expenditure program. Our ability or commitment to continue our capital expenditure program will be determined based on our evaluation of well results, commodity prices (including the impact of the dramatic increase in the Midland-Cushing oil price differentials) and the availability of capital. We do not currently expect to devote meaningful capital to the development of our other areas, but expect to devote capital to those areas to fulfill leasehold commitments and preserve core acreage to the extent we have available capital to do so. We will continue to evaluate new organic opportunities for growth and will continue to evaluate pursuing stressed or distressed acquisition opportunities that may arise in this low commodity price environment. See “Capital Resources and Liquidity” for a further discussion of our existing credit facility and possible refinancing.

Southern Delaware Basin

Our first five Southern Delaware Basin wells were brought on production during 2017. During the six months ended June 30, 2018, we brought three additional wells on production, the Ragin Bull #3H (Wolfcamp A), River Rattler #1H (Wolfcamp B) and Ragin Bull #2H (Wolfcamp B), with average maximum 30 day initial production rates (“IP”) of

Table of Contents

1,070 Boed (67% oil), 1,225 Boed (74% oil), and 734 Boed (66% oil), respectively. The River Rattler #1H, our first Wolfcamp B test, has had the best 24-hour IP (1,416 Boed) and 30-day IP of all our wells in the Southern Delaware Basin. We continue to identify cost efficiencies in our drilling efforts, as evidenced by the fact that these three wells averaged less than 27 days from spud to total measured depth ("TMD").

In July 2018, we brought two more wells on production which were drilled from a common pad, the Sidewinder #1H (49% WI, 37% NRI) targeting the Wolfcamp A formation and the Gunner #3H (47% WI, 35% NRI) targeting the Wolfcamp B. The Sidewinder #1H was drilled to a TMD of 20,550 feet, including a 10,500 foot lateral, and had a 30-day IP of 368 Boed (70% oil). The Gunner #3H was drilled to a TMD of 20,167 feet, including a 10,067 foot lateral, and had a 30-day IP of 773 Boed (78% oil).

On July 1, 2018, we spud the Fighting Ace #2H (50% WI, 38% NRI) targeting the Wolfcamp A, which was drilled to a TMD of 20,560 feet, including a 10,598 foot lateral. Completion operations on this well are expected to commence in mid-August, with initial production expected in mid-September.

On August 2, 2018, we spud the General Paxton #1H (50% WI, 38% NRI) in the southeast quadrant of our acreage position. This well will target the Wolfcamp A formation and is expected to have a TMD of approximately 20,000 feet, including a lateral of approximately 10,000 feet. From there, we expect to move the rig approximately five miles to the northwest and spud the River Rattler #4H. After that, we will evaluate our strategy for the remainder of the year, given the dramatic increase in the Midland-Cushing oil differentials in the area.

Impairment of Long-Lived Assets

We recognized $2.7 million in impairment of proved properties during the six months ended June 30, 2018, including a $2.3 million impairment of proved properties related to our Vermilion 170 offshore property during the three months ended March 31, 2018 and a $0.4 million impairment of non-core onshore proved properties for the three months ended June 30, 2018. Under GAAP, an impairment charge is required when the unamortized capital cost of any individual property within the Company's producing property base exceeds the risked estimated future net cash flows from the proved, probable and possible reserves for that property. We recognized impairment expense of approximately $0.4 million and approximately $1.2 million for the three and six months ended June 30, 2018, respectively, related to impairment of certain non-core unproved properties primarily due to expiring non-core leases.

Summary Production Information

Our production for the three months ended June 30, 2018 was approximately 56% offshore and 44% onshore and was comprised of 59% natural gas, 24% oil and 17% natural gas liquids. Our production for the three months ended June 30, 2017 was 68% offshore and 32% onshore and was comprised of approximately 68% natural gas, 16% oil and 16% natural gas liquids.

Table of Contents

The table below sets forth our average net daily production data in Mmcfe/d for each of our fields for each of the periods indicated:

	Three Months Ended June 30, 2017	September 30, 2017	December 31, 2017	March 31, 2018	June 30, 2018
Offshore GOM					
Dutch and Mary Rose (1)	36.3	32.2	30.8	29.0	21.0
Vermilion 170 (2)	3.1	4.2	3.5	3.0	2.7
South Timbalier 17 (3)	0.2	0.1	—	—	—
Southeast Texas (4)	8.2	7.8	7.5	7.3	6.4
South Texas (5)	5.6	4.6	5.8	5.3	4.5
West Texas	3.3	3.2	3.2	4.5	6.7
Other (6)	1.3	1.1	1.0	0.9	1.1
	58.0	53.2	51.8	50.0	42.4

(1) Includes a decreased production rate of 4.2 Mmcfe/d due to downtime related to compressor installation and maintenance during the three months ended June 30, 2018.
(2) Includes a decreased production rate of 0.8 Mmcfe/d due to temporary pipeline limitations during the three months ended June 30, 2017.
(3) South Timbalier 17 ceased production in August 2017.
(4) Includes Woodbine production from Madison and Grimes counties and conventional production in others.
(5) Includes Eagle Ford and Buda production from Karnes, Zavala and Dimmit counties, and conventional production in others. Includes a decreased production rate of 0.7 Mmcfe/d during the three months ended June 30, 2018 due to Karnes County sale during three months ended March 31, 2018.
(6) Includes onshore wells primarily in East Texas and Wyoming.

Other Investments

Jonah Field - Sublette County, Wyoming

Our wholly owned subsidiary, Contaro Company ("Contaro") currently has a 37% ownership interest in Exaro. As of June 30, 2018, Exaro had 647 wells on production over its 5,760 gross acres (1,040 net), with a working interest between 2.4% and 32.5%. These wells were producing at a rate of approximately 23 Mmcfe/d, net to Exaro.
The current operator of these interests has applied for multiple drilling permits for horizontal wells that will be located on parts of our acreage. Exaro's working interest in the drilling spacing units for the applied for horizontal wells ranges from 1% to 6%. As a result of our investment in Exaro, we recognized an investment loss of approximately $0.5

million, net of no tax expense, for the three months ended June 30, 2018, and an investment gain of $0.2 million, net of no tax expense, for the three months ended June 30, 2017. For the six months ended June 30, 2018 and 2017, we recognized an investment gain of approximately $0.2 million, net of no tax expense, and $2.0 million, net of no tax expense, respectively, as a result of our investment in Exaro. See Note 8 to our Financial Statements - “Investment in Exaro Energy III LLC” for additional details related to this investment.

Table of Contents

Results of Operations for the Three and Six Months Ended June 30, 2018 and 2017

The table below sets forth revenue, production data, average sales prices and average production costs associated with our sales of natural gas, oil and natural gas liquids ("NGLs") from operations for the three and six months ended June 30, 2018 and 2017. Oil, condensate and NGLs are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of oil, condensate or NGL is the energy equivalent of six thousand cubic feet (“Mcf”) of natural gas. Reported operating expenses include production taxes, such as ad valorem and severance taxes.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	%	2018	2017	%
Revenues (thousands):						
Oil and condensate sales	$ 9,607	$ 6,483	48 %	$ 18,418	$ 12,025	53 %
Natural gas sales	5,848	11,135	(47) %	14,457	22,275	(35) %
NGL sales	2,993	2,658	13 %	6,010	5,400	11 %
Total revenues	$ 18,448	$ 20,276	(9) %	$ 38,885	$ 39,700	(2) %
Production:						
Oil and condensate (thousand barrels)						
Offshore GOM	18	33	(45) %	37	55	(33) %
Southeast Texas	29	38	(24) %	62	82	(24) %
South Texas	25	23	9 %	53	49	8 %
West Texas	70	37	89 %	122	46	165 %
Other	9	11	(18) %	18	24	(25) %
Total oil and condensate	151	142	6 %	292	256	14 %
Natural gas (million cubic feet)						
Offshore GOM	1,695	2,908	(42) %	3,991	5,916	(33) %
Southeast Texas	265	340	(22) %	565	675	(16) %
South Texas	197	276	(29) %	431	605	(29) %
West Texas	80	33	142 %	126	33	282 %
Other	42	50	(16) %	79	106	(25) %
Total natural gas	2,279	3,607	(37) %	5,192	7,335	(29) %
Natural gas liquids (thousand barrels)						
Offshore GOM	59	83	(29) %	137	167	(18) %
Southeast Texas	24	29	(17) %	50	58	(14) %
South Texas	10	16	(38) %	24	30	(20) %
West Texas	18	8	125 %	25	8	213 %
Other	—	—	— %	—	1	(100) %
Total natural gas liquids	111	136	(18) %	236	264	(11) %
Total (million cubic feet equivalent)						
Offshore GOM	2,156	3,602	(40) %	5,033	7,248	(31) %
Southeast Texas	580	747	(22) %	1,240	1,517	(18) %
South Texas	412	509	(19) %	890	1,083	(18) %
West Texas	606	304	99 %	1,008	359	181 %
Other	100	115	(13) %	187	250	(25) %
Total production	3,854	5,277	(27) %	8,358	10,457	(20) %

Daily Production:								
Oil and condensate (thousand barrels per day)								
Offshore GOM	0.2	0.4	(45)	%	0.2	0.3	(33)	%
Southeast Texas	0.3	0.4	(24)	%	0.3	0.5	(24)	%
South Texas	0.3	0.3	9	%	0.3	0.3	8	%
West Texas	0.8	0.4	89	%	0.7	0.3	165	%
Other	0.1	0.1	(18)	%	0.1	—	(25)	%
Total oil and condensate	1.7	1.6	6	%	1.6	1.4	14	%

Table of Contents

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	%	2018	2017	%
Natural gas (million cubic feet per day)						
Offshore GOM	18.6	32.0	(42) %	22.1	32.7	(33) %
Southeast Texas	2.9	3.7	(22) %	3.1	3.7	(16) %
South Texas	2.2	3.0	(29) %	2.4	3.3	(29) %
West Texas	0.9	0.4	142 %	0.7	0.2	282 %
Other	0.4	0.5	(16) %	0.4	0.6	(25) %
Total natural gas	25.0	39.6	(37) %	28.7	40.5	(29) %
Natural gas liquids (thousand barrels per day)						
Offshore GOM	0.6	0.9	(29) %	0.8	0.9	(18) %
Southeast Texas	0.3	0.3	(17) %	0.3	0.3	(14) %
South Texas	0.1	0.2	(38) %	0.1	0.2	(20) %
West Texas	0.2	0.1	125 %	0.1	0.1	213 %
Other	—	—	— %	—	—	(100) %
Total natural gas liquids	1.2	1.5	(18) %	1.3	1.5	(11) %
Total (million cubic feet equivalent per day)						
Offshore GOM	23.7	39.6	(40) %	27.8	40.0	(31) %
Southeast Texas	6.4	8.2	(22) %	6.9	8.4	(18) %
South Texas	4.5	5.6	(19) %	4.9	6.0	(18) %
West Texas	6.7	3.3	99 %	5.6	2.0	181 %
Other	1.1	1.3	(13) %	1.0	1.4	(25) %
Total production	42.4	58.0	(27) %	46.2	57.8	(20) %
Average Sales Price:						
Oil and condensate (per barrel)	$ 63.53	$ 45.61	39 %	$ 63.16	$ 46.99	34 %
Natural gas (per thousand cubic feet)	$ 2.57	$ 3.09	(17) %	$ 2.78	$ 3.04	(9) %
Natural gas liquids (per barrel)	$ 26.84	$ 19.50	38 %	$ 25.32	$ 20.40	24 %
Total (per thousand cubic feet equivalent)	$ 4.79	$ 3.84	25 %	$ 4.65	$ 3.80	22 %
Expenses (thousands):						
Operating expenses	$ 6,478	$ 6,329	2 %	$ 13,405	$ 13,162	2 %
Exploration expenses	$ 394	$ 284	39 %	$ 863	$ 375	130 %
Depreciation, depletion and amortization	$ 9,498	$ 12,714	(25) %	$ 19,983	$ 24,485	(18) %
Impairment and abandonment of oil and gas properties	$ 777	$ 1,401	(45) %	$ 4,104	$ 1,431	187 %
General and administrative expenses	$ 5,354	$ 5,833	(8) %	$ 12,080	$ 12,429	(3) %
Gain (loss) from investment in affiliates (net of taxes)	$ (475)	$ 166	(386) %	$ 232	$ 1,950	(88) %
Selected data per Mcfe:						
Operating expenses	$ 1.68	$ 1.20	40 %	$ 1.60	$ 1.26	27 %
General and administrative expenses	$ 1.39	$ 1.11	25 %	$ 1.45	$ 1.19	22 %
Depreciation, depletion and amortization	$ 2.46	$ 2.41	2 %	$ 2.39	$ 2.34	2 %

Three months ended June 30, 2018 Compared to Three months ended June 30, 2017

Natural Gas, Oil and NGL Sales and Production

All of our revenues are from the sale of our natural gas, oil and NGL production. Our revenues may vary significantly from year to year depending on production volumes and changes in commodity prices, each of which may fluctuate widely. Our production volumes are subject to significant variation as a result of new operations, weather events, transportation and processing constraints and mechanical issues. In addition, our production naturally declines over time as we produce our reserves.

Table of Contents

We reported revenues of $18.4 million for the three months ended June 30, 2018, compared to revenues of $20.3 million for the three months ended June 30, 2017. The decrease in revenues was primarily attributable to lower gas production related in large part to a shut in at the Dutch and Mary Rose Field due to a compressor installation, partially offset by the higher percentage in production from oil and the benefit of higher oil and natural gas liquids prices.

Total equivalent production was 42.4 Mmcfe/d for the three months ended June 30, 2018, compared to 58.0 Mmcfe/d in the prior year quarter. This expected year over year decline in equivalent production volumes was mitigated in part by the fact that the percentage of production from higher-value oil and natural gas liquids increased from 32% to 41%. As the year progresses, that percentage should continue to increase due to our oil-weighted drilling program. The three months ended June 30, 2018 included a 4.2 Mmcfe/d decrease in production due to downtime related to an offshore compressor installation and maintenance and a 0.7 Mmcfe/d decrease in production due to the sale of our Karnes County properties.

Average Sales Prices

The average equivalent sales price realized for the three months ended June 30, 2018 was $4.79 per Mcfe compared to $3.84 per Mcfe for the three months ended June 30, 2017. This increase was attributable primarily to the increase in the realized price of oil to $63.53 per barrel, compared to $45.61 per barrel for the three months ended June 30, 2017, and to the increase in the realized price of natural gas liquids to $26.84 per barrel, compared to $19.50 per barrel for the three months ended June 30, 2017. The increase in the average equivalent price also was a result of the increase in oil and liquids as a percentage of total production.

Approximately half of our second quarter revenues were derived from oil sales, especially in West Texas, which is our largest oil producing area. Our oil in West Texas is sold at prices related to Midland hub pricing, which has been and remains subject to a significant negative price differential, compared to Cushing hub West Texas Intermediate pricing. This negative pricing differential increased from an average of ($0.83) per barrel for the three months ended June 30, 2017 to an average of ($5.15) per barrel for the three months ended June 30, 2018. Recently, the Midland–Cushing negative differential per barrel has substantially increased above historical levels.

Operating Expenses

Operating expenses for the three months ended June 30, 2018 were approximately $6.5 million, or $1.68 per Mcfe, compared to $6.3 million, or $1.20 per Mcfe, for the three months ended June 30, 2017. The table below provides additional detail of operating expenses for the three month periods:

	Three Months Ended June 30,			
	2018		2017	
	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)
Lease operating expenses	$ 4,852	1.26	$ 4,195	$ 0.79
Production & ad valorem taxes	836	0.22	709	0.13
Transportation & processing costs	285	0.07	1,073	0.20
Workover costs	505	0.13	352	0.08
Total operating expenses	$ 6,478	1.68	$ 6,329	$ 1.20

Lease operating expenses increased by 16% for the three months ended June 30, 2018, compared to the three months ended June 30, 2017, primarily due to our new West Texas properties. The increase in the average expense per unit was due to overall lower production from other areas, primarily offshore, for the three months ended June 30, 2018.

Transportation and processing costs decreased by 73% for the three months ended June 30, 2018, compared to the three months ended June 30, 2017, primarily due to lower offshore production and a prior period adjustment related to an offshore processing fee overcharge. In addition, primarily all of our offshore gas production is now routed through one pipeline instead of two, which has resulted in lower costs.

Impairment Expenses

Impairment expenses for the three months ended June 30, 2018 included a $0.4 million impairment of non-core onshore proved properties and a $0.4 million impairment of unproved properties. Impairment expenses for the three months ended June 30, 2017 were $1.4 million related to the partial impairment of two unused offshore platforms which were subsequently sold.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the three months ended June 30, 2018 was approximately $9.5 million, or $2.46 per Mcfe. This compares to approximately $12.7 million, or $2.41 per Mcfe, for the three months ended June 30, 2017. The lower depletion expense for the three months ended June 30, 2018 was primarily attributable to lower production.

General and Administrative Expenses

Total general and administrative expenses for the three months ended June 30, 2018 were approximately $5.4 million, compared to $5.8 million for the three months ended June 30, 2017. These expenses are primarily related to cash compensation and benefits, stock-based compensation, professional fees and office costs. General and administrative expenses included approximately $1.6 million in non-cash stock-based compensation, for both the current and prior year quarters.

Gain (Loss) from Affiliates

For the three months ended June 30, 2018 and June 30, 2017, we recorded a loss from affiliates of approximately $0.5 million, net of no tax expense, and a gain of $0.2 million, net of no tax expense, respectively, related to our investment in Exaro.

Six months ended June 30, 2018 Compared to Six months ended June 30, 2017

Natural Gas, Oil and NGL Sales and Production

All of our revenues are from the sale of our natural gas, oil and NGL production. Our revenues may vary significantly from year to year depending on production volumes and changes in commodity prices, each of which may fluctuate widely. Our production volumes are subject to significant variation as a result of new operations, weather events, transportation and processing constraints and mechanical issues. In addition, our production naturally declines over time as we produce our reserves.

We reported revenues of $38.9 million for the six months ended June 30, 2018, compared to revenues of $39.7 million for the six months ended June 30, 2017. The decrease in revenues was attributable to lower gas production, primarily from natural decline in the Dutch and Mary Rose Field and the shut in at this field due to a compressor installation, partially offset by the higher percentage in production from oil and the benefit of higher oil and natural gas liquids prices.

Total equivalent production was 46.2 Mmcfe/d for the six months ended June 30, 2018, compared to 57.8 Mmcfe/d in the prior year. This expected year over year decline in equivalent production volumes was mitigated in part by the fact that the percentage of production from higher-value oil and natural gas liquids increased from 30% to 38%. As the year progresses, that percentage should continue to increase due to our oil-weighted drilling program. The six months ended June 30, 2018 included a 2.0 Mmcfe/d decrease in production due to downtime related to an offshore compressor installation and maintenance.

Average Sales Prices

The average equivalent sales price realized for the six months ended June 30, 2018 was $4.65 per Mcfe compared to $3.80 per Mcfe for the six months ended June 30, 2017. This increase was attributable primarily to the increase in the realized price of oil to $63.16 per barrel, compared to $46.99 per barrel for the six months ended June 30, 2017, and to the increase in the realized price of natural gas liquids to $25.32 per barrel, compared to $20.40 per barrel for the six months ended June 30, 2017. The increase in the average equivalent price also was a result of the increase in oil and liquids as a percentage of total production.

Table of Contents

Almost half of our first six month revenues were derived from oil sales, especially in West Texas, which is our largest oil producing area. Our oil in West Texas is sold at prices related to Midland hub pricing, which has been and remains subject to a significant negative price differential compared to Cushing hub West Texas Intermediate pricing. This negative pricing differential increased from an average of ($0.30) per barrel for the six months ended June 30, 2017 to an average of ($2.39) per barrel for the six months ended June 30, 2018. Recently, the Midland–Cushing negative differential per barrel has substantially increased above historical levels.

Operating Expenses

Operating expenses for the six months ended June 30, 2018 were approximately $13.4 million, or $1.60 per Mcfe, compared to $13.2 million, or $1.26 per Mcfe, for the six months ended June 30, 2017. The table below provides additional detail of operating expenses for the six month periods:

	Six Months Ended June 30,			
	2018		2017	
	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)
Lease operating expenses	$ 9,896	$ 1.18	$ 8,843	$ 0.85
Production & ad valorem taxes	1,618	0.19	1,368	0.13
Transportation & processing costs	882	0.11	2,114	0.20
Workover costs	1,009	0.12	837	0.08
Total operating expenses	$ 13,405	1.60	$ 13,162	$ 1.26

Lease operating expenses increased by 12% for the six months ended June 30, 2018, compared to the six months ended June 30, 2017, primarily due to our new West Texas properties. The increase in the average expense per unit was due to overall lower production from other areas, primarily offshore, for the six months ended June 30, 2018.

Transportation and processing costs decreased by 58% for the six months ended June 30, 2018, compared to the six months ended June 30, 2017, primarily due to lower offshore production and a prior period adjustment related to an offshore processing fee overcharge. In addition, primarily all of our offshore gas production is now routed through one pipeline instead of two, which has resulted in lower costs.

Impairment Expenses

Impairment expenses for the six months ended June 30, 2018 were $3.9 million and included approximately $2.7 million impairment due to revised reserve estimates of onshore and offshore proved properties and approximately $1.2 million impairment primarily due to expiring leases of non-core onshore unproved properties. Impairment expenses for the six months ended June 30, 2017 were $1.4 million related to the impairment of two unused offshore platforms which were subsequently sold.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the six months ended June 30, 2018 was approximately $20.0 million, or $2.39 per Mcfe. This compares to approximately $24.5 million, or $2.34 per Mcfe, for the six months ended June 30, 2017. The lower depletion expense for the six months ended June 30, 2018 was primarily attributable to lower production.

General and Administrative Expenses

Total general and administrative expenses for the six months ended June 30, 2018 were approximately $12.1 million, compared to $12.4 million for the six months ended June 30, 2017. These expenses are primarily related to cash compensation and benefits, stock-based compensation, professional fees and office costs. General and administrative expenses included approximately $3.0 million and $3.1 million in non-cash stock-based compensation, for the current and prior year periods, respectively.

Table of Contents

Gain from Affiliates

For the six months ended June 30, 2018 and June 30, 2017, we recorded a gain from affiliates of approximately $0.2 million, net of no tax expense, and a gain of $2.0 million, net of no tax expense, respectively, related to our investment in Exaro.

Gain from Sale of Assets

Gain from sale of assets for the six months ended June 30, 2018 was approximately $10.8 million, including a $9.4 million gain from the sale of our operated Eagle Ford Shale assets in Karnes County, Texas and a $1.4 million gain from the sale of our non-operated assets in Starr County, Texas. Gain from sale of assets for the six months ended June 30, 2017 was approximately $2.5 million, which included a $2.9 million gain related to the sale of all of our assets in the Bob West North area and our operated assets in the Escobas area, both located in Southeast Texas, partially offset by a $0.4 million loss on the sale of inventory.

Other Income (Expense)

Other income for the six months ended June 30, 2018 was $0.9 million, which was primarily related to a reimbursement claim under our property and casualty insurance policy. Other expense for the six months ended June 30, 2017 was $30 thousand.

Capital Resources and Liquidity

During the six months ended June 30, 2018, we incurred expenditures of $29.0 million on capital projects, including $24.7 million for the drilling and completion of wells in the Southern Delaware Basin and $3.6 million in leasehold acquisition and other non-drilling costs in the Southern Delaware Basin. For the remainder of 2018, we have budgeted to drill three wells and complete two wells, after which we intend to review the amount and timing of our remaining 2018 capital expenditure program. Our ability or commitment to continue our capital expenditure program will be determined based on our evaluation of well results, commodity prices (including the impact of the dramatic increase in the Midland-Cushing oil price differentials) and the availability of capital.

Cash From Operating Activities

Cash flows from operating activities provided approximately $13.3 million in cash for the six months ended June 30, 2018 compared to $18.1 million provided by operating activities for the same period in 2017. The table below provides additional detail of cash flows from operating activities for the six months ended June 30, 2018 and 2017:

	Six Months Ended June 30,	
	2018	2017
	(in thousands)	
Cash flows from operating activities, exclusive of changes in working capital accounts	$ 11,902	$ 14,785
Changes in operating assets and liabilities	1,361	3,324
Net cash provided by operating activities	$ 13,263	$ 18,109

Cash From Investing Activities

Net cash flows used in investing activities, which were comprised of capital expenditures net of proceeds from asset sales, were $8.5 million for the six months ended June 30, 2018. We expended $30.1 million in cash capital costs, primarily related to drilling and/or completing wells in the Southern Delaware Basin and acquiring or extending unproved leases during the six months ended June 30, 2018, partially offset by $21.6 million provided by the sale of our properties in Karnes County, Texas and non-operated properties in Starr County, Texas. Cash flows used in investing activities for the six months ended June 30, 2017 were $34.9 million, substantially all of which was used for capital expenditures related to drilling and/or completing wells in the Southern Delaware Basin and acquiring or extending unproved leases.

Table of Contents

Cash From Financing Activities

Cash flows used in financing activities for the six months ended June 30, 2018 were approximately $4.7 million, primarily related to net repayment of borrowings outstanding under our credit facility. Cash flows provided by financing activities for the six months ended June 30, 2017 were approximately $16.8 million, primarily related to net borrowings under our credit facility.

RBC Credit Facility

In October 2013, we entered into a four-year $500 million secured revolving credit facility with Royal Bank of Canada and other lenders ("RBC Credit Facility"), the maturity of which has been extended by subsequent amendment to October 1, 2019. The borrowing base is redetermined each November and May. As of June 30, 2018, the borrowing base under the RBC Credit Facility was $110 million, but was reduced to $105 million effective August 1, 2018, as agreed to during the May 2018 redeterminations.

The RBC Credit Facility contains restrictive covenants which, among other things, restrict the declaration or payment of dividends by Contango and require a Current Ratio of greater than or equal to 1.0 and a Leverage Ratio of less than or equal to 3.50, both as defined in the RBC Credit Facility Agreement. As of June 30, 2018, we were in compliance with all but the Current Ratio covenant under the RBC Credit Facility, although we obtained a waiver for such non-compliance effective for June 30, 2018. The RBC Credit Facility also contains events of default that may accelerate repayment of any borrowings and/or termination of the facility. Events of default include, but are not limited to, payment defaults, breach of certain covenants including the current ratio covenant, bankruptcy, insolvency or change of control events.

Over the past few months, we have been in discussions with our current lenders and other sources of capital regarding a possible refinancing and/or replacement of our existing RBC Credit Facility, which refinancing could include an issuance of a combination of various types of debt and equity. These discussions have included a possible new, replacement or extended credit facility that would be expected to provide additional borrowing capacity for future capital expenditures. There is no assurance, however, that such discussions will result in a refinancing of the RBC Credit Facility on acceptable terms or provide any specific amount of additional liquidity for future capital expenditures.

Application of Critical Accounting Policies and Management's Estimates

Significant accounting policies that we employ and information about the nature of our most critical accounting estimates, our assumptions or approach used and the effects of hypothetical changes in the material assumptions used to develop each estimate are presented in Note 2 to our Financial Statements – "Summary of Significant Accounting Policies" of this report and in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – "Application of Critical Accounting Policies and Management's Estimates" in our 2017 Form 10-K.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements, see Note 2 to our Financial Statements – "Summary of Significant Accounting Policies."

Off Balance Sheet Arrangements

We may enter into off-balance sheet arrangements that can give rise to off-balance sheet obligations. As of June 30, 2018, the primary off-balance sheet arrangements that we have entered into are operating lease agreements, which are customary in the oil and gas industry. Other than the off-balance sheet arrangements shown under operating leases in the commitments and contingencies table included in our 2017 Form 10-K, we have no other off-balance sheet arrangements that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

We are exposed to various risks including energy commodity price risk for our natural gas and oil production. When oil, natural gas and natural gas liquids prices decline significantly, our ability to finance our capital budget and operations may be adversely impacted. Our major commodity price risk exposure is to the prices received for our oil, natural gas and natural gas liquids production. Realized commodity prices received for our production are tied to the spot prices applicable to natural gas and crude oil at the applicable delivery points. Prices received for oil, natural gas and natural gas liquids are volatile and unpredictable. For the three and six months ended June 30, 2018, a 10% fluctuation in the prices received for natural gas and oil production would have had an approximate $1.8 million and $3.9 million impact on our revenues, respectively.

Derivative Instruments and Hedging Activity

We expect energy prices to remain volatile and unpredictable, therefore we have designed a risk management strategy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our cash flows. The types of derivative instruments that we typically utilize include swaps and costless collars. The total volumes which we hedge through the use of our derivative instruments varies from period to period, however, generally our objective is to hedge approximately 50% of forecasted production from proved developed producing reserves (excluding forecasted offshore production during hurricane season), at the time of hedging, for the following twelve to eighteen months. Our hedge strategy and objectives may change significantly as our operational profile changes and/or commodity prices change.

We are exposed to market risk on our open derivative contracts related to potential nonperformance by our counterparties. It is our policy to enter into derivative contracts, including interest rate swaps, only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The counterparties to our current derivative contracts are large financial institutions and also lenders or affiliates of lenders in our RBC Credit Facility. We are not required to post collateral, or pay margin calls, under any of these contracts as they are secured under our RBC Credit Facility.

We have also been exposed to interest rate risk on our variable interest rate debt. If interest rates increase, our interest expense would increase and our available cash flow would decrease. Currently, we do not have any derivative contracts to reduce the exposure to market rate fluctuations. At June 30, 2018, we did not have any open positions that converted our variable interest rate debt to fixed interest rates. We continue to monitor our risk exposure as we incur future indebtedness at variable interest rates and will look to continue our risk management policy as situations present themselves.

We account for our derivative activities under the provisions of ASC 815, Derivatives and Hedging, (“ASC 815”). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. The estimated fair values for financial instruments under ASC 825, Financial Instruments (“ASC 825”) are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Note 5 to our Financial Statements - "Derivative Instruments" for more details.

Interest Rate Sensitivity

We are exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR and US Prime based and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on these obligations.

As of June 30, 2018, our total long-term debt was $80.8 million, which bears interest at a floating or market interest rate that is tied to the prime rate or LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. During the six months ended June 30, 2018, our effective rates fluctuated between 4.9% and 8.0%, depending on the term of the specific debt drawdowns. At June 30, 2018, we did not have any outstanding interest rate swap agreements. As of June 30, 2018, the weighted average interest rate on our variable rate debt was 5.75% per year.

Table of Contents

Assuming our current level of borrowings, a 100 basis point increase in the interest rates we pay under our RBC Credit Facility would result in an increase of our interest expense by $0.4 million for the six month period.

Other Financial Instruments

As of June 30, 2018, we had no cash or cash equivalents based on our cash management policy. Investments in fixed-rate, interest-earning instruments carry a degree of interest rate and credit rating risk. Fixed-rate securities may have their fair market value adversely impacted because of changes in interest rates and credit ratings. Additionally, the value of our investments may be impaired temporarily or permanently. Due in part to these factors, our investment income may decline and we may suffer losses in principal. Currently, we do not use any derivative or other financial instruments or derivative commodity instruments to hedge any market risks, including changes in interest rates or credit ratings, and we do not plan to employ these instruments in the future. Because of the nature of the issuers of the securities that we invest in, we do not believe that we have any cash flow exposure arising from changes in credit ratings. Based on a sensitivity analysis performed on the financial instruments held as of June 30, 2018, an immediate 10% change in interest rates would result in a $0.5 million change on our near-term financial condition or results of operations.

Item 4. Controls and Procedures

Our President and Chief Executive Officer, together with our Chief Financial and Accounting Officer, carried out an evaluation of the effectiveness of the Company’s “disclosure controls and procedures” as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), as of June 30, 2018. Based upon that evaluation, the Company’s management concluded that, as of June 30, 2018, the Company’s disclosure controls and procedures were effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and to ensure that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our President and Chief Executive Officer and our Chief Financial and Accounting Officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in the Company’s internal control over financial reporting that occurred during the three months ended June 30, 2018 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting. However, the adoption of Accounting Standard Codification 606, Revenue from Contracts with Customers (“ASC 606”) in January 2018, did require the implementation of new accounting processes during the three months ended June 30, 2018, which changed the Company's internal controls relating to revenue by reviewing new contracts or modifications to existing contracts, as well as any significant increase in sales level on a quarterly basis to monitor the significance of ASC 606 going forward.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of legal proceedings, see Note 11 to our Financial Statements – “Commitments and Contingencies.”

Item 1A. Risk Factors

There have been no material changes from the risk factors disclosed in Item 1A of Part 1 of our Annual Report on Form 10-K for the year ended December 31, 2017 and in Item 1A of Part II of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018.

Table of Contents

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The Company repurchased the following shares from employees during the three months ended June 30, 2018 for the payment of withholding taxes due on shares of restricted stock that vested and were issued under its stock-based compensation plans:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that may yet be Purchased Under Program
April 2018	32,288	$ 3.69	—	$ —
May 2018	1,271	$ 3.77	—	$ —
June 2018	144	$ 4.93	—	$ —
Total	33,703	$ 3.70	—	$ 31.8 million

Item 3. Defaults upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Tax Benefit Preservation Plan

On August 1, 2018, the Board of Directors (the “Board”) of Contango declared a dividend of one right (a “Right”) for each of the Company’s issued and outstanding shares of common stock. The dividend will be issued to the stockholders of record at the close of business on August 13, 2018, the Record Date. Each Right entitles the registered holder, subject to the terms of the Rights Agreement (as defined below), to purchase from the Company one one-thousandth of a share of Series A Junior Participating Preferred Stock, $0.04 par value per share (the “Preferred Stock”), of the Company, at a price of $33.72, subject to certain adjustments. The description and terms of the Rights are set forth in the Rights Agreement dated as of August 1, 2018 (the “Rights Agreement”) between the Company and Continental Stock Transfer & Trust Company, as Rights Agent. A copy of the Rights Agreement has been filed with the SEC as an exhibit to a Current Report on Form 8-K filed on August 2, 2018.

In connection with the adoption of the Rights Agreement, the Board adopted a Certificate of Designations of the Preferred Stock. The Certificate of Designations was filed with the Secretary of State of the State of Delaware and became effective on August 1, 2018.

The purpose of the Rights Agreement is to diminish the risk that the Company’s ability to use its net operating losses and certain other tax assets to reduce potential future federal income tax obligations would become subject to limitations by reason of the Company’s experiencing an “ownership change,” as defined in Section 382 of the Internal Revenue Code of 1986, as amended (the “Tax Code”). A company generally experiences such an ownership change if the percentage of its stock owned by its “5-percent shareholders,” as defined in Section 382 of the Tax Code, increases by more than 50 percentage points over a rolling three-year period. The Rights Agreement is designed to reduce the likelihood that the Company will experience an ownership change under Section 382 of the Tax Code by (i) discouraging any person or group from becoming a 4.95% shareholder and (ii) discouraging any existing 4.95% shareholder from acquiring additional shares of the Company’s common stock.

Table of Contents

Item 6. Exhibits

Exhibit Number	Description
3.1	Certificate of Incorporation of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K dated December 1, 2000, as filed with the Securities and Exchange Commission on December 15, 2000 and incorporated by reference herein).
3.2	Amendment to the Certificate of Incorporation of Contango Oil & Gas Company (filed as Exhibit 3.4 to the Company's Quarterly Report on Form 10-QSB for the quarter ended September 30, 2002, as filed with the Securities and Exchange Commission on November 14, 2002 and incorporated by reference herein).
3.3	Third Amended and Restated Bylaws of Contango Oil & Gas Company (filed as Exhibit 3.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, as filed with the Securities and Exchange Commission on March 3, 2015 and incorporated by reference herein).
3.4	Certificate of Designations of Series A Junior Participating Preferred Stock of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K dated August 1, 2018, as filed with the Securities and Exchange Commission on August 2, 2018 and incorporated by reference herein).
4.1	Rights Agreement, dated as of August 1, 2018, between Contango Oil & Gas Company, as the Company, and Continental Stock Transfer & Trust Company, as Rights Agent (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K dated August 1, 2018, as filed with the Securities and Exchange Commission on August 2, 2018, and incorporated by reference herein).
10.1	Fifth Amendment to Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders signatory thereto. †
31.1	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934. †
31.2	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934. †
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. †
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. †
101	Interactive Data Files †

†Filed herewith.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereto duly authorized.

CONTANGO OIL & GAS COMPANY

Date: August 8, 2018	By:	/s/ ALLAN D. KEEL
		Allan D. Keel President and Chief Executive Officer (Principal Executive Officer)
Date: August 8, 2018	By:	/s/ E. JOSEPH GRADY
		E. Joseph Grady Senior Vice President and Chief Financial and Accounting Officer (Principal Financial and Accounting Officer)